UPTON RESOURCES INC.

TECHNICAL EXCELLENCE & HIGH QUALITY ASSETS

ANNUAL REPORT
2002

UPTON RESOURCES INC.

ANNUAL REPORT TO SHAREHOLDERS

Upton Resources Inc. was founded in 1987 as an exploration and development company based in southeast Saskatchewan. Since then the company has added high quality light oil from the northern U.S. and natural gas from the northwest of Alberta to its portfolio.

Upton is an oil and gas company with a solid history of teamwork, expertise and dedication. We focus on efficient, low cost operations and strive to add high quality assets by applying our strong technical expertise. 2002 resulted in strong financial results and operating results. We are very proud of our achievements and pleased to present our 2002 annual report to shareholders.

2002 Highlights

Cash flow from operations and cash flow from operations per share for 2002 set record highs for the company for the third year in a row and increased to $36.9 million (up 22 percent) and $1.89 per share (up 7 percent) while earnings were $6.6 million and $0.34 per share.

The year 2002 was highlighted by the second quarter acquisition of Empire Energy Inc. Upton acquired southeast Saskatchewan light and medium oil production of approximately 1,600 barrels per day and proven reserves of 2.6 million barrels of oil equivalent (boe) a day and probable reserves of 1.3 million boe a day. The acquisition provided solid cash flow and an excellent inventory of development locations that Upton began exploiting through the second half of the year.

Proved reserves increased 15.7 percent to 10 million barrels of oil equivalent, primarily as a result of the Empire acquisition. Upton's proved developed producing reserves (PV 10 percent) accounted for 84 percent of total proved reserve value of $108 million, while the total proved reserve value was 86 percent of established reserve value of $127.2 million. Probable reserves were flat at 5.4 million barrels of oil equivalent (boe).

Upton enjoyed strong oil prices beginning in the second quarter and achieved high netbacks for oil properties as average production reached record levels of 5,517 barrels of oil equivalent per day for the year. Operating netbacks were $22.54 per barrel of oil equivalent for 2002 and all-in cash netbacks were $18.32.

HIGHLIGHTS

For the three months and year-ending December 31, 2002
($000's except where noted)

	Three Months 2002	Three Months 2001	Three Months Change	Twelve Months 2002	Twelve Months 2001	Twelve Months Change
FINANCIAL HIGHLIGHTS						
Revenues	**$ 19,127**	$ 11,129	72%	**$ 69,187**	$ 55,323	25%
Cash flow from operations	**$ 10,103**	$ 5,956	70%	**$ 36,887**	$ 30,345	22%
Basic cash flow from operations per share	**$ 0.49**	$ 0.35	40%	**$ 1.89**	$ 1.76	7%
Diluted cash flow from operations per share	**$ 0.48**	$ 0.34	41%	**$ 1.85**	$ 1.73	7%
Net earnings (loss)	**$ (260)**	$ 255	(202%)	**$ 6,648**	$ 8,532	(22%)
Basic net earnings (loss) per share	**$ (0.01)**	$ 0.01	(200%)	**$ 0.34**	$ 0.50	(32%)
Diluted net earnings (loss) per share	**$ (0.01)**	$ 0.01	(200%)	**$ 0.33**	$ 0.49	(33%)
Capital expenditures - including corporate acquisitions	**$ 11,856**	$ 9,633	23%	**$ 81,040**	$ 32,707	148%
Capital expenditures - excluding corporate acquisitions	**$ 11,856**	$ 9,633	23%	**$ 39,064**	$ 32,707	19%
Bank debt including working capital deficit	**$ 52,813**	$ 33,145	59%	**$ 52,813**	$ 33,145	59%
Average basic shares outstanding	**20,601**	17,167	20%	**19,524**	17,229	13%
Average diluted shares outstanding	**21,063**	17,441	21%	**19,916**	17,532	14%
Basic shares outstanding	**20,632**	17,162	20%	**20,632**	17,162	20%
OPERATING HIGHLIGHTS						
Daily volumes						
- oil - barrels/day	**5,416**	4,335	25%	**5,114**	4,349	18%
- gas sales - mmcf/day	**2.180**	1.453	50%	**2.415**	1.441	68%
- total barrels of oil equivalent/day (6:1)*	**5,779**	4,577	26%	**5,517**	4,589	20%
Drilling activity						
- gross wells	**16.0**	11.0	5.0	**50.0**	51.0	(1.0)
- net wells	**12.3**	7.9	4.4	**36.8**	32.4	4.4
Reserves						
- total proved - boe	**10,026.5**	8,668.7	16%	**10,026.5**	8,668.7	16%
- total probable - boe	**5,445.4**	5,428.8	1%	**5,445.4**	5,428.8	1%
- established (proved +50% probable) - boe	**12,749.2**	11,383.1	12%	**12,749.2**	11,383.1	12%
- NPV Established at 10% ($ million)**	**$ 127.2**	$ 94.6	34%	**$ 127.2**	$ 94.6	34%

* (6:1) All natural gas sales volumes are converted on the basis of 1 Bbl of crude oil for 6 Mcf of natural gas.
** (Before income tax and Saskatchewan capital tax and including Alberta royalty tax credit)

Operating Results

Fourth quarter production increased 26 percent over 2001 to 5,779 barrels of oil equivalent per day. Oil production increased 25 percent to 5,416 barrels of oil per day, while natural gas sales were up 50 percent to 2.2 million cubic feet per day.

Upton drilled 16 gross (12.3 net) wells in the fourth quarter. Except for a deep gas exploration well at Strachan, Alberta (0.35 net) that was wet in the primary target zone, Upton concentrated on development drilling in southeast Saskatchewan. Four (4.0 net) wells at Midale, two (0.8 net) at Heward and six (4.7 net) at Wauchope, Innes, Rock Lake, Glen Ewen and Melrose were successful oil producers. Vertical step-out and re-entry wells at Heward and Arcola were completed as salt water disposal wells. A vertical step out at Melrose (1.0 net) was unsuccessful.

In the fourth quarter at Larne in northwest Alberta, Upton's partner tied in a previously completed Sulphur Point natural gas well (Upton 50 percent W.I.) and brought on gas production in early November at 425 mcfd net to Upton.

For the year 2002, production volumes increased 20 percent to 5,517 barrels of oil equivalent per day. Crude oil sales were up 18 percent to 5,114 barrels per day, largely due to the Empire acquisition. Natural gas sales increased 68 percent to 2.4 million cubic feet per day attributed to the Larne Bistcho area of northwest Alberta, which had an additional 7 (2.9 net) wells brought on production in the year.

Upton drilled 50 (36.8 net) wells in 2002. By core area 38 (29.9 net) were drilled in southeast Saskatchewan, 5 (4.2 net) in the northern U.S. and 7 (2.7 net) in Alberta.

For the three months and year-ending December 31, 2002
($000's except where noted)

	Three Months			**Twelve Months**		
	2002	2001	Change	**2002**	2001	Change
Netbacks ($/boe) except where noted						
- oil ($/bbl)	**$ 37.63**	$ 23.31	61%	**$ 35.69**	$ 33.06	8%
- gas ($/mcf)	**$ 4.65**	$ 2.57	81%	**$ 3.49**	$ 3.33	5%
- wellhead	**$ 37.02**	$ 22.90	62%	**$ 34.61**	$ 32.38	7%
- hedge	**$ (1.04)**	$ 3.53	(129%)	**$ (0.25)**	$ 0.65	(138%)
- net realized	**$ 35.98**	$ 26.43	36%	**$ 34.36**	$ 33.03	4%
Royalty costs	**$ 7.13**	$ 4.23	69%	**$ 7.11**	$ 6.70	6%
Operating costs	**$ 5.37**	$ 4.19	28%	**$ 4.71**	$ 4.10	15%
Operating netback	**$ 23.48**	$ 18.01	30%	**$ 22.54**	$ 22.23	1%
General & Admin	**$ 2.27**	$ 2.50	(9%)	**$ 2.20**	$ 2.19	0%
Interest	**$ 1.06**	$ 0.72	47%	**$ 0.92**	$ 0.89	3%
Capital Taxes	**$ 1.14**	$ 0.64	78%	**$ 1.10**	$ 1.02	8%
Cash netback	**$ 19.01**	$ 14.15	34%	**$ 18.32**	$ 18.13	1%

Financial Results

In the fourth quarter a 26 percent increase in daily volumes and a 36 percent increase in realized commodity prices resulted in a 70 percent increase in cash flow from operations to $10.1 million and a 40 percent increase in basic cash flow from operations per share to $0.49.

Upton recorded a loss of $260,000 and $0.01 per share basic in the fourth quarter. This was negatively impacted by depletion of $10.0 million in the quarter. The Empire acquisition had a cost effective influence on the depletion rate but other expenditures did not substantially increase proved reserves for the period.

Fourth quarter revenues increased 72 percent over 2001 to $19.1 million. Upton's average royalty rate was 19.8 percent. Operating costs increased to $5.37 per barrel of oil equivalent. Production increases in Upton's higher cost areas of northwest Alberta and the northern U.S. increased operating costs per barrel of oil equivalent, while southeast Saskatchewan averaged $4.28 per barrel equivalent in the quarter. General and administrative expense on a per barrel of oil equivalent basis was down 9 percent to $2.27 as the Empire acquisition was made with limited additional G & A. Interest charges increased to $564,000 and in the quarter, up due to the partial debt financing of the Empire acquisition.

Capital spending in the quarter was $11.9 million, of which $7.4 million was for drilling, $1.2 million for land and seismic, and $3.3 million for facilities and equipment. Capital expenditures in Alberta in the fourth quarter were $1.8 million, primarily for Upton's fourth quarter cost for the Strachan well, with the balance of expenditures in southeast Saskatchewan.

Upton's year-end debt and working capital deficit was $52.8 million. The ratio of net debt and working capital deficiency to fourth quarter annualized cash flow was 1.3 times.

For the year 2002, cash flow from operations increased 22 percent to $36.9 million, while basic cash flow from operations per share increased 7 percent to $1.89. West Texas Intermediate averaged $26.08 per barrel up marginally from $25.90 in 2001. Production volume increases of 20 percent contributed to most of the growth.

Earnings were $6.6 million, down 22 percent from 2001. Basic earnings per share were $0.34, down 32 percent. The results were influenced by higher depletion charges.

Revenues increased 25 percent driven primarily from production volume increases. Upton's 2002 average royalty rate was 20.7 percent. Operating costs averaged $4.71 per barrel of oil equivalent, an increase of 15 percent due to similar factors that influenced the fourth quarter results. Both operating netbacks at $22.54 per barrel of oil equivalent and all-in cash netbacks of $18.32 were up marginally from 2001. On an equivalent barrel basis interest costs, general and administrative expenses, and capital taxes (primarily the Saskatchewan resource surcharge on revenue) increased 3 percent year-over-year.

Capital spending, excluding corporate acquisitions, was $39.1 million on program costs of which $21.1 million was invested in southeast Saskatchewan, $9.7 million in the northern U.S., and $8.3 million in Alberta.

Bank debt and working capital deficiency was $52.8 million at December 31, 2002, for a trailing debt to cash flow ratio of 1.4 times. Debt increased year-over-year due to the partial debt financing of the Empire acquisition. Capital stock increased by $12.9 million and 3.5 million shares also due to the Empire acquisition.

Outlook

On January 27, 2003 Upton announced that it had commenced a process to explore strategic alternatives designed to maximize shareholder value. Subsequently the Board of Upton engaged Tristone Capital Inc. and Yorkton Securities Inc. as financial advisors. At the time of writing this report, the process is underway and results will be communicated to shareholders as soon as possible.

I would like to extend sincere thanks to Upton's team of management, head office employees and field staff, who work diligently throughout the year to implement our strategic objectives and to maintain Upton as an efficient and profitable producer.

On behalf of the Board of Directors,

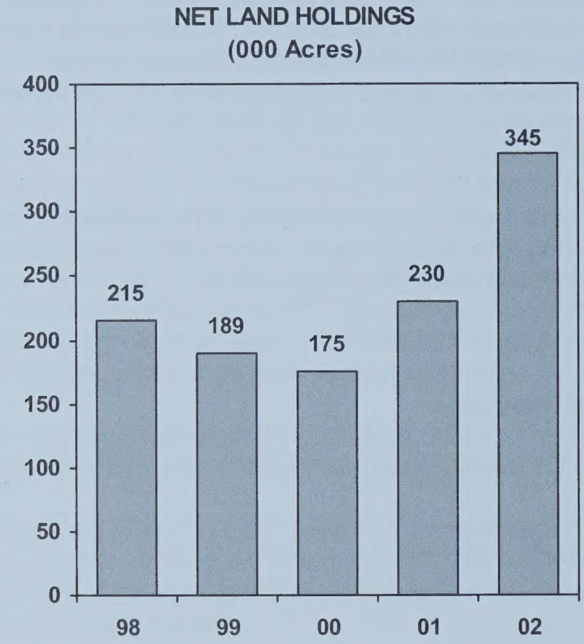
G. Scott Dutton
President and Chief Executive Officer

April 30, 2003

REVIEW OF EXPLORATION AND OPERATIONS

2002 Total Land Holdings

Acres	Gross	Net	WI%
Developed	46,976	28,258	60.15%
Undeveloped	554,084	316,959	57.20%
Total	601,060	345,217	57.43%



Undeveloped Land Reconciliation

Acres	Gross	Net
Undeveloped land January 1, 2002	328,033	202,158
Acquisitions and reallocations	277,665	154,086
Expiries and reallocations	(51,614)	(39,285)
Undeveloped land December 31, 2002	554,084	316,959

Net Undeveloped Land by Core Area

	2002	2001	Increase/(Decrease)
NW Alberta	**64,833**	61,826	3,007
Northern U.S.	**53,306**	59,698	(6,392)
SE Saskatchewan	**198,820**	80,634	118,186
Total	**316,959**	202,158	114,801

2002 Drilling Results

	Development				Total		Total		Grand Total	
	Horizontal		Vertical		Development		Exploration			
Wells	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	28	22.3	0	0	28	22.3	3	2.8	31	25.1
Gas	0	0	0	0	0	0	6	2.2	6	2.2
Dry	0	0	1	1.0	1	1.0	4	3.5	5	4.5
Other	0	0	6	3.8	6	3.8	2	1.2	8	5.0
Total	28	22.3	7	4.8	35	27.1	15	9.7	50	36.8
Operated	27	22.1	7	4.8	34	26.9	8	7.0	42	33.9
Non-Operated	1	0.2	0	0	1	0.2	7	2.7	8	2.9
Success Rate	100%	100%	100%	79%	97%	96%	73%	64%	90%	88%
Average Interest		80%		63%		77%		65%		74%

Major Producing Properties

BOE	Current	2002		2001		2000	
	April 12/03	**Volume**	**% of Total**	Volume	% of Total	Volume	% of Total
SE Saskatchewan	5,127	**4,623**	**84%**	3,940	86%	4,067	95%
U.S. Properties	516	**584**	**10%**	510	11%	196	5%
NW Alberta	155	**310**	**6%**	139	3%	0	0%
Total	5,798	**5,517**	**100%**	4,589	100%	4,263	100%

Major Properties Drilling Summary, Production, Land, Average Working Interest and Crude Quality

Area	2002 Drilled Wells		2002 Average Production		Net Undeveloped	Average WI	Crude Quality
	Gross	Net	BOEPD	% of Total	Land, Acres	%	API, deg
SE Saskatchewan	38	29.9	4,623	84%	198,820	72%	29-37
U.S. Properties	5	4.2	584	10%	53,306	50%	40
NW Alberta	7	2.7	310	6%	64,833	24%	
Total	50	36.8	5,517	100%	316,959		

Reconciliation of Changes in Reserves

	Oil, mstb			Gas, mmcf			BOE, mstb (Gas 6:1)		
	Proven	Probable	Total	Proven	Probable	Total	Proven	Probable	Tot
Balance December 31, 1999	8,919.7	4,023.3	12,943.0	-	-	-	8,919.7	4,023.3	12,943.
Additions	1,359.8	960.7	2,320.5	-	-	-	1,359.8	960.7	2,320.
Acq./Sales of Reserves	-	-	-	-	-	-	-	-	
Revisions of Prior Estimates	145.9	(997.7)	(851.8)	-	-	-	145.9	(997.7)	(851.8
2000 Production	(1,560.4)	-	(1,560.4)	-	-	-	(1,560.4)	-	(1,560.4
Balance December 31, 2000	8,865.0	3,986.3	12,851.3	-	-	-	8,865.0	3,986.3	12,851.
Additions	1,664.3	1,161.7	2,826.0	2,248.0	4,937.9	7,185.9	2,039.0	1,984.7	4,023.
Acq./Sales of Reserves	(705.0)	(263.1)	(968.1)	-	-	-	(705.0)	(263.1)	(968.1
Revisions of Prior Estimates	(27.7)	(314.0)	(341.7)	1,035.0	210.0	1,245.0	144.8	(279.0)	(134.2
2001 Production	(1,587.3)	-	(1,587.3)	(525.8)	-	(525.8)	(1,674.9)	-	(1,674.9
Balance, December 31, 2001	8,209.2	4,570.8	12,780.0	2,757.2	5,147.9	7,905.1	8,668.7	5,428.8	14,097.
Additions	329.0	102.6	431.6	1,152.8	-	1,152.8	521.1	102.6	623.
Acq./Sale of Reserves	2,570.3	1,245.9	3,816.2	439.0	157.0	596.0	2,643.5	1,272.1	3,915.
Revisions of Prior Estimates	215.2	(899.9)	(684.7)	(50.9)	(2,748.9)	(2,799.8)	206.7	(1,358.0)	(1,151.3
2002 Production	(1,870.0)	-	(1,870.0)	(861.4)	-	(861.4)	(2,013.6)	-	(2,013.6
Balance December 31, 2002	9,453.8	5,019.5	14,473.3	3,436.7	2,556.0	5,992.7	10,026.6	5,445.5	15,472.

Columns may not add due to rounding

Major Properties Reserves and Net Present Value

	2002 Year-End Reserves				Net Present Value@ 12%*, M$		
Area	**Proven**	**Probable**	**Total**	**% of Total**	Total Proven	Established	% of Established
SE Saskatchewan	**7,711**	**3,036**	**10,746**	**70%**	83,871	95,709	80%
U.S. Properties	**1,882**	**2,046**	**3,928**	**25%**	14,045	18,286	15%
NW Alberta	**434**	**364**	**798**	**5%**	4,643	5,833	5%
Total BOE	**10,027**	**5,446**	**15,472**	**100%**	102,559	119,828	100%

* Estimated future net revenues before income taxes and Saskatchewan capital taxes, discounted at 12% as evaluated in the Reserve Evaluation

Reserves Life Index and Reserve Replacement Ratio

Reserves Comparison	2002 (mboe)	2001 (mboe)	2000 (mboe)
Proven (mbbls)	**10,027**	8,669	8,865
Probable (mbbls)	**5,446**	5,429	3,986
Total (mbbls)	**15,472**	14,097	12,851
Established	**12,750**	11,383	10,858
Q4 Annualized Production	**2,127**	1,670	1,645
Reserve Life Index			
Proven (yrs)	**4.7**	5.2	5.4
Established (yrs)	**6.0**	6.8	6.6
Total Proven and Probable (mbbls)	**7.3**	8.4	7.8
Reserve Additions, Net of Revisions and Acquisitions			
Proven (mbbls)	**3,371**	2,184	1,505
Established (mbbls)	**3,380**	3,036	1,487
Total Proved and Probable (mbbls)	**3,388**	3,890	1,468
Reserve Replacement Ratio			
Proven	**1.6**	1.3	0.9
Established	**1.6**	1.8	0.9
Total Proven and Probable	**1.6**	2.3	0.9

Upton Resources Inc. Escalated NPV Comparison

Present Value of Future Cash Flow ($ millions)

	2002				2001			
Discounted at	**0%**	**10%**	**12%**	**15%**	0%	10%	12%	15%
Total Proven	**152.9**	**108.0**	**102.5**	**95.5**	114.3	78.4	74.0	68.5
Probable	**76.3**	**38.4**	**34.5**	**29.8**	61.0	32.3	29.2	25.3
Grand Total Proven and Probable	**229.2**	**146.4**	**137.0**	**125.3**	175.3	110.7	103.2	93.8
Established	**191.1**	**127.2**	**119.8**	**110.4**	144.8	94.6	88.6	81.2

Note: Estimated future net present value before income taxes and Saskatchewan capital tax from the Reserves Evaluation

Upton Resources Inc. Constant Dollar NPV Comparison

Present Value of Future Cash Flow ($ millions)

	2002*				2001*			
Discounted at	0%	10%	12%	15%	0%	10%	12%	15%
Total Proven	**215.7**	**149.1**	**141.0**	**130.6**	108.8	76.2	72.2	67.0
Probable	**109.3**	**56.3**	**50.8**	**44.2**	54.3	29.8	26.9	23.4
Grand Total Proven and Probable	**325.0**	**205.4**	**191.8**	**174.8**	163.1	106.0	99.1	90.4
Established	**270.4**	**177.3**	**166.4**	**152.7**	135.9	91.1	85.7	78.7

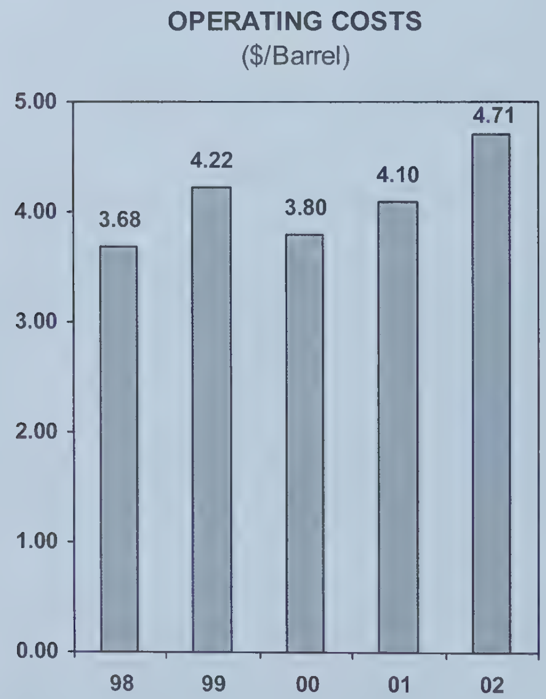
* 2002: Oil $40.08/bbl CDN ($29.39 U.S. WTI), Gas $5.16/mcf CDN

* 2001: Oil $29.51/bbl CDN ($21.00 U.S. WTI), Gas $3.39/mcf CDN

Note: Estimated future net present value before income taxes and Saskatchewan capital tax from the Reserves Evaluation

Crude Oil & Natural Gas Escalating Price Forecast as of January 1, 2003

Year	WTI @ Cushing U.S.$/bbl	CDN/U.S.$ Exchange Rate	WTI @ Cushing CDN$/bbl	EDM Ref Price CDN$/bbl	Henry Hub U.S.$/mmbtu	AECO "C" CDN$/ mmbtu
2003	26.00	0.650	40.00	38.96	4.15	5.60
2004	24.00	0.650	36.92	35.86	3.90	5.20
2005	22.50	0.650	34.62	33.53	3.70	4.88
2006	22.95	0.650	35.31	34.20	3.75	4.94
2007	23.41	0.650	36.01	34.89	3.80	5.00
2008	23.88	0.650	36.73	35.59	3.85	5.06
2009	24.35	0.650	37.47	36.30	3.90	5.12
2010	24.84	0.650	38.22	37.02	3.95	5.18
2011	25.34	0.650	38.98	37.76	4.00	5.24
2012	25.85	0.650	39.76	38.52	4.05	5.30
2013	26.36	0.650	40.56	39.29	4.10	5.36
2014	26.89	0.650	41.37	40.08	4.15	5.41
2015	27.43	0.650	42.20	40.88	4.20	5.47
2016	27.98	0.650	43.04	41.69	4.25	5.53
2017	28.54	0.650	43.90	42.53	4.33	5.63



MANAGEMENT'S DISCUSSION AND ANALYSIS

(all tabular figures in thousands of dollars, unless otherwise noted)

Highlights

The highlights of Upton Resources Inc.'s financial performance for the year-ended December 31, 2002 are summarized as follows:

- Basic cash flow from operations increased 22 percent from 2001 to $36.9 million, while cash flow from operations per share was 7 percent higher at $1.89.
- Daily average sales volumes increased by 20 percent to 5,517 barrels of oil equivalent (boe) per day from the 2001 total of 4,589 boe per day. Gas is converted at a rate of 6 to 1.
- Cash netbacks remained relatively stable at $18.32 per boe in 2002 compared to $18.13 in 2001.
- Revenue increased 25 percent to $69.2 million compared to $55.3 million on sales of 2.0 million boe.
- Prices net of hedges realized during 2002 increased 4 percent to $34.36 per boe.
- Production costs increased 15 percent to $4.71 per boe.
- The depletion and depreciation provision of $26.1 million was 59 percent higher than 2001's $16.4 million.
- Upton realized earnings of $6.6 million or $0.34 basic per share compared to earnings of $8.5 million or $0.50 basic per share in 2001.
- The debt to trailing cash flow from operations ratio at year-end 2002 increased to 1.36 to 1 from 0.91 to 1 at year-end 2001.
- Canadian income tax pools increased by 63 percent to $96.0 million.
- Net capital expenditures, excluding corporate acquisitions, were $39.1 million, up 19 percent from 2001.
- Reserve additions, net of revisions, acquisitions and sales, were 3.4 million boe.
- Finding and development costs were $20.36 per boe in 2002, for a two-year average of $16.09 per boe based on total proved and probable reserves.

Operating Income

	2002	2001	% Change	2000
Oil sales	**66,623**	52,480	27	63,906
Gas sales	**3,077**	1,751	76	0
Total oil and gas sales	**69,700**	54,231	29	63,906
Hedge	**(513)**	1,092	(147)	(7,290)
Net realized oil and gas revenue	**69,187**	55,323	25	56,616
Royalties	**14,314**	11,229	27	14,242
Production expenses	**9,489**	6,867	38	5,926
Operating income	**45,384**	37,227	22	36,448
Netbacks ($ per boe, unless otherwise stated)				
Oil sales ($ per barrel)	**35.69**	33.06	8	40.96
Gas sales ($ per mcf)	**3.49**	3.33	5	0
Total oil and gas sales	**34.61**	32.38	7	40.96
Hedge price	**(0.25)**	0.65	(138)	(4.68)
Total sales price per boe (6:1)	**34.36**	33.03	4	36.28
Royalties	**7.11**	6.70	6	9.13
Production expenses	**4.71**	4.10	15	3.80
Operating netback	**22.54**	22.23	1	23.35

Upton's operating income increased 22 percent to $45.4 million in 2002. Additional production from 7(2.9 net) new wells in northwest Alberta increased gas sales 68 percent to 2.4 mmcf per day and contributed $3.1 million to revenues in 2002. The Empire acquisition from April 2002 added approximately 1,600 barrels of oil per day increasing annual sales volumes by 18 percent to 5,114 barrels of oil per day and contributing $66.6 million to revenues in 2002. Improving West Texas Intermediate prices, primarily in the fourth quarter, resulted in annual hedge losses of $0.5 million. Twenty percent higher sales volumes and marginally improved sales prices resulted in a 25 percent increase in revenues.

Hedging gains of $1.1 million and $0.65 per boe in 2001 reversed in 2002 with improving West Texas Intermediate prices resulting in hedging losses of $0.5 million and $0.25 per boe in 2002. Wellhead realized prices increased by 7 percent to $34.61 per boe compared to $32.38 in 2001. The change tracked WTI oil prices which rose from U.S.$25.90 in 2001 to U.S.$26.08 in 2002. In 2002, Upton had an average corporate natural gas price of $3.49 per mcf, which was lower than the industry average due to lower priced associated gas in southeast Saskatchewan. Alberta gas prices received averaged $3.85 per mcf for the year.

Royalties increased 27 percent for the year, approximately the same increase in revenues.

Sales Volumes and Production Expenses

	2002	2001	% Change	2000
Sales volume oil (mbbls)	**1,867**	1,587	18	1,560
Sales volume gas (mcf)	**881**	526	67	0
Total sales volume (6:1) (mboe)	**2,014**	1,675	20	1,560
Production expense ($ 000s)	**9,489**	6,867	38	5,926
Per boe ($)	**4.71**	4.10	15	3.80

Production expenses increased by 38 percent to $9.5 million in 2002, reflecting higher production levels. 2002 production increases in Upton's higher cost areas of northwest Alberta and the northern U.S., in addition to slightly higher operating costs per boe in southeast Saskatchewan, contributed to the increase in operating costs per boe of 15 percent to $4.71 in 2002 compared to $4.10 in 2001.

General and Administrative Expenses

	2002	2001	% Change	2000
Gross expense	**6,861**	5,816	18	5,094
Less recoveries				
Overhead	**2,079**	1,664	25	1,688
Capitalized indirect G&A overhead	**349**	479	(27)	472
Net Expenses	**4,433**	3,673	21	2,934
Average cost ($ per boe)				
Gross	**3.41**	3.47	(2)	3.27
Net	**2.20**	2.19	0	1.88
Number of employees				
Head office	**25**	26	(1)	25
Field operations	**16**	15	1	14
Total Employees	**41**	41	0	39

Staff levels remained constant in 2002 and 2001, however gross G&A costs increased 18 percent last year due to higher employee expenses, additional expenses associated with the Empire Energy acquisition and increased investor relations costs.

Capital expenditures and the number of wells drilled were similar in each of the last two years, however, the Empire acquisition increased the amount of joint venture properties and partners Upton is involved with, resulting in a 25 percent increase in overhead recoveries in 2002 compared to 2001. Capitalized indirect G&A overhead recoveries were down 27 percent as there was a lower level of exploration activity in the year. These factors resulted in a 21 percent increase in net G&A and no change in net G&A on a per boe basis.

Interest and Financial Expense

	2002	2001	% of Change	2000
Credit facility	**1,852**	1,496	24	1,872
Debenture	**-**	-	-	294
Total	**1,852**	1,496	24	2,166
Average cost ($ per boe)	**0.92**	0.89	3	1.39

Upton uses its bank line of credit for primary borrowings. The average draw on this line in 2002 was $44.3 million up from $25.0 million in 2001. Interest expense increased 24 percent to $1.9 million in 2002 due to the Empire Energy Inc. acquisition in April 2002. Although prime lending rates were lower averaging 4.2 percent in 2002 compared to 6.0 percent in 2001, debt was increased by $17.3 million in April 2002 for the cash, debt and working capital portion associated with the acquisition of Empire Energy Inc. Upton's bank line of credit was also increased to $55 million from $32 million in April 2002.

Current and Capital Taxes

	2002	2001	% of Change	2000
Federal capital taxes	**144**	92	57	32
Saskatchewan capital taxes	**2,068**	1,621	28	2,216
Current taxes	**-**	-	-	-
Total Current & Capital Tax	**2,212**	1,713	29	2,248

Saskatchewan capital taxes are 3.6 percent on oil and gas revenue from production in the province. In 2002, capital taxes increased by 29 percent to $2.2 million, due primarily to the 25 percent increase in revenues from the Empire acquisition, which was entirely Saskatchewan oil production.

Cash Flow from Operations

	2002	2001	% of Change	2000
Cash flow from operations	**36,887**	30,345	22	29,100
Production netbacks				
($ per boe, unless otherwise stated)				
Oil sales ($ per barrel)	**35.69**	33.06	8	40.96
Gas sales ($ per mcf)	**3.49**	3.33	5	0
Total oil and gas sales	**34.61**	32.38	7	40.96
Hedge	**(0.25)**	0.65	(138)	(4.68)
Net realized oil and gas sales	**34.36**	33.03	4	36.28
Less				
Royalties	**7.11**	6.70	6	9.13
Operating expenses	**4.71**	4.10	15	3.80
Operating netback	**22.54**	22.23	1	23.35
General and administrative	**2.20**	2.19	0	1.88
Interest	**0.92**	0.89	3	1.39
Current and capital tax	**1.10**	1.02	8	1.44
Cash netback	**18.32**	18.13	1	18.64
Production volume (mboe)	**2,014**	1,675	20	1,560

Upton's cash flow from operations increased by 22 percent to $36.9 million in 2002. The increase was primarily driven by an increase in sales volumes as a result of the Empire acquisition and increased gas production as cash costs on a per boe basis were relatively flat. This resulted in an average operating netback of $22.54 per boe and an average all-in cash netback of $18.32 per boe in 2002.

Depletion, Depreciation, Abandonment and Restoration

	2002	2001	% Change	2000
Depletion and depreciation	**26,120**	16,409	59	12,401
Restoration provision	**972**	793	23	832
Total	**27,092**	17,202	57	13,233
Average cost ($ per boe)	**13.45**	10.27	31	8.48

Depletion and depreciation expenses increased to $26.1 million from $16.4 million. The increased depletion and depreciation expense in 2002 primarily reflects an increase in depletable assets from over $100 million in program expenditures in the last three years, which primarily replaced production but did not add to proven reserves at a cost of over $20.00 per boe. The Empire acquisition added proven reserves in 2002 at a cost close to the 2002 depletion rate. These higher depletion costs are applied to higher sales volumes in 2002.

The site restoration abandonment expense increased to $1.0 million for 2002. Sale volumes were higher while the rate per boe was unchanged.

Future Taxes

	2002	2001	% Change	2000
Future income tax benefit	**1,420**	2,876	(51)	7,404
Future income tax benefit (liability)	**(13,409)**	-	100	-
Net future income tax benefit (liability)	**(11,989)**	2,876	317	7,404
Future tax provision	**3,147**	4,611	(32)	4,942

The 2002 future tax benefit is represented by CDN$1.4 million (U.S.$0.9 million) from Upton's U.S. subsidiary. Upton Resources U.S.A. Inc. has an additional U.S.$1.9 million of costs and losses representing tax value in excess of net book value, which are not recorded as a future tax benefit. All future tax benefits have not been recorded because the Company has not concluded that the utilization of all of these future tax benefits is "more likely than not", as per Canadian generally accepted accounting principles.

The future tax liability of $13.4 million is primarily related to the acquisition of Empire Energy Inc. Positive earnings throughout 2002 drew down the entire $1.5 million Canadian future tax asset from 2001 and recorded an additional $1.7 million future tax liability. This in addition to recording $11.7 million future tax liability from the Empire acquisition resulted in the $13.4 million future tax liability.

Net Earnings

	2002	2001	% Change	2000
Cash flow from operations	**36,887**	30,345	22	29,100
Less				
Depletion	**26,120**	16,409	59	12,401
Site restoration	**972**	793	23	832
Future tax provision	**3,147**	4,611	(32)	4,942
Net earnings	**6,648**	8,532	(22)	10,925

The higher depletion rate and higher sales volume in 2002 increased non-cash expenses by 39 percent, and caused earnings to decrease to $6.6 million.

Capital Expenditures, Reserve Additions and Finding Costs

	2002	2001	% Changed	2000
Corporate acquisitions	**41,976**	-	100	-
Less: Increase in PP&E from non-cash items including future tax liability and site restoration liability	**(11,780)**	-	(100)	-
Net corporate acquisitions for cash	**30,196**	-	100	-
Property acquisitions	-	1,548	(100)	338
Property dispositions	-	(7,289)	100	0
Land and other	**2,178**	4,041	(46)	2,556
Exploration and development	**28,707**	26,369	9	19,199
Equipment and facilities	**7,554**	7,369	3	7,025
Capitalized indirect overhead	**349**	479	(27)	472
Corporate (excluded from finding costs)	**276**	190	45	(43)
Total net capital expenditures	**69,260**	32,707	112	29,547
Reserve additions, net of revisions, acquisitions and sales (mboes)				
Proven (mboes)	**3,371**	1,479	128	1,506
Probable (mboes)	**17**	1,443	(99)	(37)
Total reserve additions	**3,388**	2,921	16	1,469
Finding costs ($ per boe)				
Proven	**20.46**	21.99	(7)	19.65
Proven plus probable	**20.36**	11.13	83	20.14
Two year rolling average				
Proven	**20.93**	20.81	1	23.94
Proven plus probable	**16.09**	14.15	14	21.49

Upton's 2002 net capital expenditure increased 19 percent to $39.1 million, excluding the Empire Energy Inc. acquisition. Including the Empire acquisition, capital expenditures increased 148 percent to $81.0 million which includes $11.7 million in additions due to the future tax liability associated with the Empire Energy purchase.

In April 2002, Upton acquired all of the outstanding shares of Empire Energy Inc. for consideration of cash, shares and the assumption of debt and working capital of $30.2 million. Production of approximately 1,600 boe/day, proven reserves of 2.6 million boe and probable reserves of 1.3 million boe were acquired.

Capital spending, excluding corporate acquisitions, of $39.1 million had $21.1 million invested in southeast Saskatchewan, $9.7 million invested in the northern U.S. and $8.3 million invested in Alberta.

Upton's drilling program in 2002 included 50 (36.8 net) wells including 38 (29.9 net) in southeast Saskatchewan, 5(4.2 net) in North Dakota and 7 (2.7 net) in Alberta. Forty five of the wells were successfully completed as oil, gas or disposal wells resulting in a 90 percent success rate.

Net Asset Value

	2002 Escalating Price			2001	
	10%	**12%**	**15%**	12%	% change
Established reserves – mboe	**12,750**	**12,750**	**12,750**	11,383	12
Net resource value*	**120,960**	**113,925**	**105,008**	83,772	36
Net land value **	**14,370**	**14,370**	**14,370**	14,151	2
Business assets	**135,330**	**128,295**	**119,378**	97,923	31
Bank debt and working capital deficit	**(52,813)**	**(52,813)**	**(52,813)**	(33,145)	(59)
Net asset value	**82,517**	**75,482**	**66,565**	64,778	17
Outstanding shares	**20,632**	**20,632**	**20,632**	17,162	20
Net asset value per share	**4.00**	**3.66**	**3.23**	3.77	(3)

* Probable values have been reduced 50 percent for risk. Net resource values are after deduction for the 3.6 percent Saskatchewan capital tax resource surcharge.

** Net land value: 2002 (201,150 acres @ $70 per acre and 115,809 acres @ $2.50 per acre), 2001 (202,158 acres @ $70 per acre)

At December 31, 2002 Upton's net asset value per share at a 12 percent discount rate was down 3 percent at $3.66 per share. Established reserves increased 12 percent. The escalating price assumptions of the Company's independent consulting engineers also increased while outstanding shares increased 20 percent due to the Empire acquisition.

Income Tax Pools

	2002	2001	% Change	2000
Canadian oil and gas property expense	**20,916**	20,193	4	24,629
Canadian development expenses	**40,879**	21,933	86	20,695
Canadian exploration expense	**12,459**	2,950	322	4,774
Undepreciated capital cost	**21,723**	13,959	56	14,142
Total Canadian tax pools	**95,977**	59,035	63	64,240
United States tax pools and losses (U.S.$)	**24,898**	21,149	18	14,423

The Company's Canadian oil and gas property expense tax pool (10 percent annual claim), Canadian development expense tax pool (30 percent annual claim), Canadian exploration expense tax pool (100 percent annual claim) and undepreciated capital cost pools increased by 63 percent by year-end 2002.

The large increase in income tax pools is for two primary reasons. First, the acquisition of Empire Energy Inc. which added $14.3 million in pools in April 2002. Secondly, the company consolidated the Canadian production operations of Empire and Upton in a partnership on May 1, 2002. Because of tax rules specific to partnerships, the partners, Upton Resources Inc. and Empire Energy Inc. (renamed Upton Oil & Gas Inc.), recognize their share of 2002 partnership income in 2003 thus deferring a drawdown of pools in 2002.

In the United States, costs and losses of U.S.$24.9 million are available to be claimed against future taxable income. Upton's U.S. future tax assets remain at U.S.$0.9 million (CDN$1.4 million), which is unchanged from 2001. The remaining U.S.$1.9 million of tax value in excess of book value was not recorded as a future tax asset in the year.

While the Company has significant tax pools to shield it from income tax in Canada, the combination of strong commodity prices and production volume growth could produce current income tax in the near term. In the U.S., future income will be shielded from income tax and Upton does not expect to pay current tax in the near term.

Bank Debt – secured by long-term assets

	2002	2001	% Change	2000
Bank debt balance – opening	**27,763**	27,200	2	22,342
Less				
Share issue net of issue cost – Empire acquisition	**12,856**	-	100	-
Share issue – options	**134**	283	(53)	114
Cash flow from operations	**36,887**	30,345	22	29,100
Dispositions of property & equipment	**-**	6,901	(100)	-
Change in working capital	**(2,673)**	2,463	(209)	(55)
Current portion of long-term debt	**-**	-	-	(3,000)
Plus				
Additions to property & equipment	**69,260**	39,996	73	29,547
Net site restoration expenditures	**-**	-	-	42
Shares purchased and cancelled	**297**	447	(34)	1,428
Foreign exchange (non-cash)	**(12)**	82	(115)	-
Net increase – bank debt	**22,341**	563	3,868	4,858
Bank debt balance – closing	**50,104**	27,763	80	27,200

Quarterly Financial Information

	2002				2001			
	Q1	**Q2**	**Q3**	**Q4**	Q1	Q2	Q3	Q4
Revenue	**11,974**	**17,811**	**20,275**	**19,127**	15,341	14,223	14,630	11,129
Net income (loss)	**1,794**	**2,113**	**3,001**	**(260)**	3,108	2,521	2,648	255
Per share basic	**0.10**	**0.11**	**0.15**	**(0.01)**	0.18	0.15	0.15	0.01
Per share diluted	**0.10**	**0.10**	**0.14**	**(0.01)**	0.18	0.14	0.15	0.01
Cash flow from operations	**6,404**	**9,103**	**11,277**	**10,103**	8,690	7,524	8,175	5,956
Per share basic	**0.37**	**0.46**	**0.55**	**0.49**	0.50	0.44	0.47	0.35
Per share diluted	**0.37**	**0.45**	**0.54**	**0.48**	0.50	0.43	0.46	0.34

Liquidity and Financial Resources

The Company's financial strategy is to fund capital expenditures from cash flow, supplemented by credit facilities and equity issues when appropriate. Upton's bank debt is expected to be within the target of 1.5 times next year's forecasted cash flow from operations using a budgeted oil price of U.S.$25 WTI. The ratio of year-end debt and working capital deficiency to twelve month trailing cash flow from operations increased to 1.43 times compared to 1.1 times in 2001. Based on a WTI oil price of U.S.$25.00 for 2003, the Company anticipates this ratio to be less than 1.5 times.

Upton's authorized credit, all of which is secured, was $55 million at year-end 2002. Current operating lines, which were reviewed and renewed in early 2003, are being finalized at the same level.

At December 31, 2002 the Company had drawn $50.1 million on the revolving credit facility, leaving $4.9 million available for additional capital expenditures and working capital needs. No principal repayments under the facility agreement are anticipated in 2003.

For the year-ended 2002, Upton had 20,631,914 common shares issued and outstanding. This balance reflects 3,499,970 shares issued pursuant to the acquisition of Empire Energy Inc., 55,500 employee options exercised, and 86,000 shares repurchased and cancelled by normal course issuer bid.

During the year 14,146,563 shares of Upton traded on The Toronto Stock Exchange, with a high of $4.60, a low of $2.57 and a closing price at December 31, 2002 of $4.15. For the year-ended 2002, the directors and officers of the Company beneficially owned 2,550,088 or 12.4 percent of the common shares.

Future Business Prospects

Industry Environment

The oil and gas industry is significantly influenced by worldwide oil prices and North American gas prices. The price of oil is affected by global events of an economic, political and environmental nature. These factors may cause an imbalance of supply and demand, which in turn affects the price of oil. The world supply and demand balance directly affects the oil price realized by Canadian producers. Prices for natural gas reflect supply and demand in North America and are impacted by drilling activity, decline rates, weather, alternative forms of energy and the strength of the economy. This price impact directly impacts cash flow and therefore the levels of capital expenditures, growth and potential for success.

Oil and Gas Prices

In 2002 the price of oil was weak in the first quarter but staged a strong comeback in the second half of the year to average U.S.$26.08 WTI for the year. During the fourth quarter, WTI averaging U.S.$28.16 per barrel. Worldwide economic activity was slow during the year which places downward pressure on worldwide oil prices. The Organization of Petroleum Exporting Countries (OPEC) has provided price support using production constraint but a war premium impacted prices. Upton's annual wellhead oil price was CDN$35.69 in 2002. Prices are also affected by the quality differential between the various grades of crude oil. Roughly 40 percent of Upton's oil production is light oil and 60 percent is a medium grade.

Gas prices began the year at low levels and increased to CDN$6.11 (AECO) for December 2002 averaging CDN$4.18 (AECO) for the year. Upton realized an average wellhead price of $3.49 per mcf in 2002. Upton's 2002 results were not significantly influenced by gas, which comprised only 6 percent of sales volumes and 4 percent of sales revenue.

The value of the Canadian dollar against its United States counterpart also influences prices for Canadian producers. Producers benefit from a lower Canadian dollar since their commodity price correlates closely to the U.S. dollar Nymex WTI. The Canadian dollar improved marginally throughout the year. It began 2002 at 1.595 and ended the year at 1.575, resulting in lower wellhead prices received. These gains were moderated by gains realized during the year from foreign exchange hedging.

2003 Operations

On January 27, 2003 the Company announced it had commenced a process to explore strategic alternatives designed to maximize shareholder value. At the time of writing this report the Company is in the maximization process and no commentary or forward looking comments can be made about the results.

The Company commenced an active drilling program in the first quarter of 2003 all focused in southeast Saskatchewan and designed to take advantage of the Company's excellent inventory of development drilling locations and very high oil prices.

First quarter cash flow is expected to be fully expended on capital expenditures resulting in first quarter debt levels similar to December 31, 2002. Second quarter capital expenditures are historically lower due to spring break up restrictions. As a result, net debt (including working capital deficit) is expected to drop by June 30, 2003. The forward plan and strategy for the second half of 2003 will be dependant on the result of the process to explore strategic alternatives to maximize shareholder value.

Cash Flow Sensitivities

Net of hedges in place (at December 31,2002 U.S. $25.00 WTI)	Impact on cash flow	$ per share
Oil price change (U.S.$1 WTI per barrel)	$2,293	$0.11
Oil sales volume change (100 barrels per day)	$737	$0.04
Gas price change (CDN$1.00 mcf AECO)	$506	$0.02
Gas sales volume change (1 mmcfd)	$1,140	$0.05
Interest rate change (one percent)	$440	$0.02
Exchange rate change (CDN$0.01)	$185	$0.01

Cash flow from operations is dependent on a number of factors, some of which are not within Upton's control. The above table indicates Upton's sensitivities to fluctuations in the industry environment anticipated for 2003.

Business Risks

The oil and gas industry confronts various risk classifications. Many of these risks are standard to all businesses, while others are specific to the petroleum exploration, development and production industry. These are summarized into operational, financial and regulatory risks in the following table.

Operational Risks and Mitigating Strategy

Risk	Mitigating Strategy
Recruiting and retaining quality professional staff.	Employs only qualified, experienced and professional staff supported by competitive compensation programs.
Finding and developing economical petroleum reserves.	Company continues to focus on areas where it has core competency.
Maintenance of reservoir production performance.	Proactively maintains and applies current technologies where appropriate.
Marketing oil production.	Contracts marketing functions to experienced, proven third party marketing professionals.
Accidental failure of various equipment used to find and develop reserves.	Maintains prudent levels of insurance for all possible contingencies.
Employee and third party, environmental and safety.	Provides ongoing safety and environmental courses and training for all applicable staff.

Financial Risks and Mitigating Strategy

Risk	Mitigating Strategy
Negative effects of market-driven commodity price.	Management has the authority to hedge the price of up to 50 percent of oil and gas production.
Negative effects of foreign exchange rate fluctuations.	Foreign exchange rate changes have a relatively minor impact on Upton's cash flow. However, foreign exchange hedge contracts are purchased where appropriate to mitigate the impact of fluctuations in the exchange rate.
Debt levels and the negative effects of interest rate changes.	The Company limits long-term debt to less than 1.5 times annual cash flow and may hedge interest rates.
Credit risk	The Company conducts all of its hedging programs with investment grade companies. All oil and gas sales contracts are done with high credit quality companies or letters of credit are secured.

Regulatory Risks and Mitigating Strategy

Risk	Mitigating Strategy
Government energy policies, taxation laws and operational laws.	Upton follows all rules and regulations required by government policies and procedures. The Company carefully monitors government policies which could significantly affect the firm.
Environmental issues, community, resident and employee needs.	All facilities are routinely maintained under high regulatory and company standards.

MANAGEMENT'S STATEMENT OF RESPONSIBILITY

The accompanying consolidated financial statements of Upton Resources Inc. were prepared by and are the responsibility of management. They have been prepared in conformity with Canadian generally accepted accounting principles. The financial information in the annual report has been reviewed to ensure consistency with the financial statements.

Management maintains systems of internal accounting control designed to provide reasonable assurance that all transactions are properly recorded in the Company's book of accounts, that procedure and policies are adhered to and that assets are safeguarded from unauthorized use.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, has been engaged, as approved by the shareholders' vote at the last annual meeting, to examine the consolidated financial statements in accordance with Canadian generally accepted auditing standards and provide an independent professional opinion.

The audit committee is composed of four members of the Board of Directors and meets quarterly with the financial officer of the Company. The external auditors of the Company have access to the audit committee to review the planning and scope of testing and to discuss the results of their audited work. On the recommendation of the audit committee, the consolidated financial statements have been approved by the Board of Directors.

Scott Dutton

G. Scott Dutton
President and Chief Executive Officer

P.H. Grubbe

Philip H. Grubbe, C.A.
Vice President, Finance and Chief Financial Officer

February 21, 2003

AUDITORS' REPORT

To the Shareholders of Upton Resources Inc.

We have audited the consolidated balance sheets of Upton Resources Inc. as at December 31, 2002 and 2001 and the consolidated statements of operations, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 21, 2003

CONSOLIDATED BALANCE SHEETS

As at December 31, 2002 and 2001

(in thousands of dollars)	**2002** **$**	2001 $
ASSETS		
Current assets		
Accounts receivable	**12,908**	8,255
Future income tax benefit (note 6)	**1,420**	2,876
Property, plant and equipment (notes 3, 4 and 12)	**135,558**	80,638
	149,886	91,769
LIABILITIES		
Current liabilities		
Accounts payable	**15,617**	13,637
Bank debt secured by long-term assets (note 4)	**50,104**	27,763
	65,721	41,400
Abandonment and restoration provision (note 3)	**4,790**	3,755
Future income tax liability (note 6)	**13,409**	-
	83,920	45,155
SHAREHOLDERS' EQUITY		
Capital stock (note 6)	**23,277**	10,364
Retained earnings	**42,689**	36,250
	65,966	46,614
	149,886	91,769
Commitments (note 11)		

Approved on Behalf of the Board

W.R. Dutton

W.R. Dutton
Director

G.H. Huntington

G.H. Huntington, C.A.
Director

CONSOLIDATED STATEMENTS OF OPERATIONS

For the years-ended December 31, 2002 and 2001

(in thousands of dollars)	2002 $	2001 $
REVENUE		
Oil and gas sales	**69,187**	55,323
Less: Royalties and production taxes	**14,314**	11,229
	54,873	44,094
EXPENSES		
Production and operation	**9,489**	6,867
General and administration	**4,433**	3,673
Interest on bank debt	**1,852**	1,496
Depletion and depreciation (note 3)	**26,120**	16,409
Abandonment and restoration provision	**972**	793
	42,866	29,238
Earnings before taxes	**12,007**	14,856
Income taxes (note 6)		
Capital taxes	**2,212**	1,713
Future taxes	**3,147**	4,611
	5,359	6,324
Net earnings for the year (note 10)	**6,648**	8,532
NET EARNINGS PER SHARE (note 9)		
Basic	**0.34**	0.50
Diluted	**0.33**	0.49

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

For the years-ended December 31, 2002 and 2001

(in thousands of dollars)	2002 $	2001 $
RETAINED EARNINGS – BEGINNING OF YEAR	**36,250**	28,108
Normal course issuer bid purchases and share cancellations (note 5)	**(209)**	(390)
Net earnings for the year	**6,648**	8,532
Retained earnings – End of year	**42,689**	36,250

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years-ended December 31, 2002 and 2001

(in thousands of dollars)	2002 $	2001 $
CASH PROVIDED BY (USED IN)		
OPERATING ACTIVITIES		
Net earnings for the year	**6,648**	8,532
Items not affecting cash		
Depletion and depreciation	**26,120**	16,409
Abandonment and restoration provision	**972**	793
Future income taxes	**3,147**	4,611
Cash flow from operations	**36,887**	30,345
Net (increase) decrease in non-cash operating working capital balances	**(8,994)**	8,020
	27,893	38,365
FINANCING ACTIVITIES		
Increase in bank debt	**22,341**	563
Issuance of capital stock	**12,990**	272
Shares repurchased	**(297)**	(466)
	35,034	369
INVESTING ACTIVITIES		
Additions to property, plant and equipment	**(69,260)**	(39,996)
Proceeds on sale of property, plant and equipment	**-**	6,901
Net decrease (increase) in non-cash working capital balances	**6,321**	(5,557)
	(62,939)	(38,652)
Foreign exchange (non-cash)	**12**	(82)
Cash – beginning and end of year	**-**	-
Cash flow from operations per share (note 9)		
Basic	**1.89**	1.76
Diluted	**1.85**	1.73
Cash expended on interest	**1,663**	1,364
Cash expended on taxes	**1,806**	2,061

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
as at December 31, 2002
(tabular amounts in thousands of dollars unless otherwise noted)

1 COMPANY ACTIVITIES

The Company is incorporated under the laws of Saskatchewan and its principal activity is the exploration, development and production of oil and gas properties.

2 SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation

The consolidated financial statements include those of the Company and its subsidiaries. Investments in jointly controlled companies, jointly controlled partnerships and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Joint ventures

Substantially all exploration and production activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Property, plant and equipment

a) Capitalized costs

The Company follows the full cost method of accounting, whereby all costs related to acquisition, exploration for and development of oil and gas reserves, whether productive or unproductive, are capitalized and accumulated in separate cost centres for Canada and the United States. Proceeds from the disposition of oil and gas properties reduce capitalized costs with no gain or loss recognized unless such disposition would significantly alter the depletion and depreciation rate.

The Company applies a ceiling test to capitalized costs on an annual basis to ensure that such costs do not exceed estimated future net revenues from production of proven reserves plus the cost of undeveloped properties net of impairment less development costs of proven undeveloped reserves, administrative, financing, and applicable income and capital tax costs.

b) Depletion and depreciation

Depletion and depreciation of resource properties and equipment are provided on the unit of production method based on total proven reserves before royalties. Unproven properties are excluded from the depletion calculation until quantities of proven reserves or impairment can be determined.

Depreciation on building, vehicles and office equipment is computed using the diminishing balance method at annual rates of 5 percent to 30 percent.

Abandonment and restoration provision

The annual provision for future abandonment and site restoration costs is based on estimates made by management and is charged to income using the unit of production method where the ratio of current year production to proven reserves determines the proportion of site restoration costs to be expensed. The accumulated amount represents the aggregate of such annual provisions less the aggregate of actual site restoration expenses incurred and adjustments resulting from property dispositions.

Foreign currency translation

The Company translates the foreign denominated monetary assets and liabilities of integrated foreign operations at the exchange rate prevailing at the year-end, non-monetary assets and liabilities are translated at historical rates of exchange, and revenues and expenses are translated at the monthly average rate of exchange. Exchange gains and losses arising on translation of the accounts are included in consolidated earnings.

Hedging activities

The Company enters into contracts to hedge crude oil prices on a portion of its crude oil production to protect its future earnings and cash flows from the potential adverse impact of low crude oil prices and not for speculative purposes. Gains or losses on these contracts are included in revenues at the time of sale of the related hedged production.

In addition, the Company enters into contracts to fix the U.S./Canadian dollar exchange rate as well as contracts to fix interest rates on banker's acceptances entered into by the Company. Gains or losses on these contracts are included in revenues as the contracts expire.

Income taxes

The Company follows the liability method of tax allocation accounting. Under this method, recognition of a future tax liability or asset is dependent on the expected tax outflow or benefit to be derived from differences between the carrying value and tax basis of assets and liabilities.

Stock-based compensation plans

The Company has stock-based compensation plans. These are described in note 5. The company does not recognize any expense related to its stock-based compensation for share options granted to employees or directors. The impact on pro-forma earnings and pro-forma earnings per share, using the fair value method is disclosed in note 5. Options can be exercised for common shares. Any consideration paid by employees on exercise of stock options or purchase of stock is credited to share capital.

Measurement uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas properties and equipment and the provision for abandonment and restoration costs are based on estimates. The ceiling test is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods, could be significant.

Earnings per share

Earnings and cash flow per share are calculated using the weighted average number of common shares outstanding during the year. Diluted earnings and cash flow from operations per share are calculated under the treasury stock method (see note 9).

3 PROPERTY AND EQUIPMENT

	2002 **$**	2001 $
Petroleum properties	**316,289**	235,525
Other property and equipment	**3,505**	3,229
	319,794	238,754
Less: Accumulated depletion and depreciation	**(184,236)**	(158,116)
	135,558	80,638

Capitalized expenditures relating to unproven properties which includes land costs and related seismic costs excluded from the depletion base are as follows:

	2002 **$**	2001 $
Canada	**4,364**	2,209
United States	**1,507**	2,041
	5,871	4,250

In 2001, the Company sold several non-core properties for cash proceeds of $6,901,000. The carrying value of oil and gas properties was reduced by $7,289,000 including the associated accumulated site restoration liability which was reduced by $388,000 for the year.

In 2002, the Company capitalized indirect general and administrative overhead costs of $349,000 (2001 – $479,000) relating to exploration and development activity.

In 2002, the Company calculated its year-end ceiling test using the December monthly corporate average wellhead oil price of $40.08 per barrel and sales gas price of $5.16 per thousand cubic feet. No ceiling test write down was required as a result of this test at December 31, 2002.

At year-end, the estimated total future site restoration costs outstanding were $10,532,000 (2001– $8,165,000). A liability of $4,790,000 (2001 - $3,755,000) has been recognized to date for these future site restoration costs.

Total depletable assets have been reduced by the estimated salvage value of $11,533,000 (2001– $8,489,000).

4 BANK DEBT

	2002	2001
	$	$
Credit facility	**50,104**	27,741
Mortgage	**-**	22
	50,104	27,763

Credit facilities

The Company has a $55,000,000 (2001 – $32,000,000) revolving demand credit facility with a banking syndicate. As at December 31, 2002 the Company had drawn $50,104,000 (2001 - $27,741,000) from the credit facility consisting of a $9,104,000 demand loan and $41,000,000 in bankers' acceptances. The demand loan interest is paid monthly in arrears at the bank's pricing grid which is dependent on the Company's ratio of total debt to the most recent quarterly annualized cash flow. The bankers' acceptance interest is paid in advance and bears interest at the bank's prime acceptance fee rate with a stamp fee which is also subject to the bank's pricing grid. At year-end, the demand loan carried an annual rate of the bank's prime rate plus 0.375 percent and the banker's acceptances carried a stamp fee of 1.375 percent.

The credit facility is reviewed annually by the bank and provided certain covenants are met, no principal repayments will be required in the next twelve months. As at December 31, 2002 the Company is in compliance with its debt covenants.

Security for the loan facility includes a $150,000,000 fixed and floating charge demand debenture over the Company's oil and gas properties and a general assignment of book debts of the company.

5 CAPITAL STOCK

Authorized

Unlimited number of common shares

Issued and outstanding

	Number of shares	Amount $
Balance – December 31, 2000	17,195,840	10,167
Options exercised or cancelled for intrinsic value	110,371	283
Shares purchased and cancelled under normal course issuer bid	(140,800)	(85)
Former employee shares cancelled	(2,967)	(1)
Balance – December 31, 2001	17,162,444	10,364
Shares issued (note 12)	3,499,970	12,880
Share issue costs	-	(24)
Tax benefit on issue costs	-	11
Options exercised	55,500	134
Shares purchased and cancelled under normal course issuer bid	(86,000)	(88)
Balance – December 31, 2002	20,631,914	23,277

Pursuant to a normal course issuer bid throughout the year, the Company purchased 86,000 of its outstanding shares at an average cost of $3.46 per share. The total cost of acquiring these shares was $297,399 of which $209,043 exceeded the average carrying value and was charged to retained earnings.

Stock-based compensation

The Company has adopted the new CICA 3870 standard for reporting stock-based compensation for stock options granted after January 1, 2002. As now required by Canadian generally accepted accounting principles, the impact on net earnings and net earnings per share of such compensation costs, using the fair value method, is disclosed. The total fair value of the Company's options on June 22, 2002 is $498,416.

	$
Net earnings	
Reported	6,648,000
Pro-forma	6,384,000
Net earnings per common share	
Reported	0.34
Pro-forma	0.33

The fair value for options granted to employees and directors was estimated at the date of grant using a Black-Scholes Option Pricing Model with the following assumptions for 2002:

Volatility factor of expected market price	0.45
Weighted average risk free rate	4.29%
Weighted average expected life in years	3.75
Weighted average expected annual dividends per share	-

Under the original and the 1996 plans, which were consolidated into one plan in the current year, the Company may grant up to 2,009,744 shares to its employees for the year-ending 2002. Under both plans, the exercise price of each option equals the market price of the Company's stock on the date of the grant. The stock options vest over various periods up to 3 years from the date of grant with maximum terms ranging from 5 to 8 years.

In May of 2002, the Company adopted a policy cancelling the ability for options to be exercised for their intrinsic value in cash or common shares. As of this time, options can now only be exercised for common shares.

A summary of the status of the Company's stock option plans as of December 31, 2002 and 2001, and changes during the years-ending on those dates is presented below:

		2002		2001
	Shares (000's)	**Weighted-average Exercise price**	Shares (000's)	Weighted-average exercise price
Outstanding – Beginning of year	**1,486**	**$3.15**	1,628	$3.00
Granted	**396**	**3.47**	232	3.44
Exercised	**(55)**	**2.41**	(110)	2.16
Cancelled for intrinsic value	**(74)**	**2.15**	(112)	1.96
Forfeited (cancelled)	**(14)**	**3.42**	(152)	3.66
Outstanding – End of year	**1,739**	**$3.28**	1,486	$3.15
Options exercisable – End of year	**1,355**		1,268	

The following table summarizes information about fixed stock options outstanding at December 31, 2002.

	Options outstanding			**Options exercisable**	
Range of exercise prices	Number outstanding at December 31, 2002	Weighted-average remaining contractual life (years)	Weighted-average exercise price	Number exercisable at December 31, 2002	Weighted-average exercise price
$1.00 to $1.99	162,400	0.8	$1.67	162,400	$1.67
$2.00 to $2.99	628,000	1.5	$2.55	628,000	$2.55
$3.00 to $4.99	781,400	3.6	$3.55	397,600	$3.62
$5.00 to $8.99	104,000	1.3	$5.05	104,000	$5.05
$9.00 to $9.99	63,000	2.0	$9.75	63,000	$9.75
	1,738,800	2.9	$3.28	1,355,000	$3.25

Effective November 18, 1998 the Board of Directors implemented a Shareholder Rights Protection Plan ("the plan") which was approved at the annual and special meeting of shareholders on May 19, 1999. The plan defines the terms of a Permitted Bid in the event of a take-over offer for the Company and among other conditions requires that no shares be taken up under the Bid for a minimum of 45 days and a minimum level of shares being tendered. The plan is intended to provide the Board of Directors with adequate time to maximize shareholder value and to protect Upton shareholders from unfair, abusive or cohesive take-over strategies.

6 INCOME TAXES

The provision for future income taxes reflects an effective tax rate that differs from the expected Canadian income tax rate. The differences are as follows:

	2002 **$**	2001 $
Expected combined Canadian federal and provincial income tax rate	**44.59%**	44.97%
Expected provision for (recovery of) income taxes	**5,354**	6,681
Increase (decrease) resulting from		
Royalties and production taxes paid to the Crown	**2,824**	2,313
Resource allowance on Canadian resource income	**(5,051)**	(4,123)
Tax rate change	**-**	112
Previously unrecognized U.S. losses	**(91)**	(346)
Capital taxes	**2,212**	1,713
Other	**111**	(26)
Provision for income taxes	**5,359**	6,324

The future income tax liability or benefit is composed of temporary differences and future income tax reductions. The following table shows the tax-affected amounts of those items with a tax value in excess of their net book value:

	2002 **$**	2001 $
Share issue costs	**63**	17
Tax value of property and equipment in excess of net book value	**(3,381)**	1,641
Future site restoration deductions	**1,602**	1,261
Partnership deferred income	**(10,280)**	-
Other future deductions	**7**	(43)
Future income tax benefit (liability)	**(11,989)**	2,876

Future income tax asset (liability) is comprised of:

	2002 $	2001 $
Upton Resources U.S.A. Inc.	**1,420**	1,433
Upton Resources Inc.	**(13,409)**	1,443
	(11,989)	2,876

At December 31, the following deductions were available to claim against future taxable income:

	2002 $	2001 $
Canadian exploration expense	**12,459**	2,950
Canadian development expense	**40,879**	21,933
Canadian oil and gas property expense	**20,916**	20,193
Undepreciated capital cost	**21,723**	13,959
	95,977	59,035

In addition, the Company has costs and losses of U.S.$24,897,567 (2001 – U.S.$21,149,258) which may be claimed against future income in the United States. At December 31, 2002, on an after-tax basis, the tax value of the U.S. assets exceed the net book value by U.S.$2,801,149 (2001– U.S.$2,854,868). Of this amount, U.S.$900,000 (CDN$1,419,840) is recorded as a future tax benefit. Based on management's best estimate, this is the amount estimated as more likely than not to be realized in the near future. A future tax asset has not been recognized for the remaining U.S.$1,901,149 (2001 – U.S.$1,954,868).

7 RELATED PARTY TRANSACTIONS

At December 31, the Company has the following transactions and balances with companies controlled by certain directors and officers of the Company:

	2002 $	2001 $
Accounts receivable	**77**	68
Accounts payable	**-**	5

The Company operates oil wells for companies in which certain directors have ownership interests. These transactions were made under normal business terms and conditions and at the same rates as with non-related parties

Included in accounts receivable are two sets of non-interest bearing loans which have been offered to employees and officers for the purpose of acquiring shares in the Company. At December 31, 2002, the Company had non-interest bearing loans due from its officers of $103,601 (2001 – $147,178) and employees of $27,281 (2001 – $71,869). The loans were used to purchase shares and are secured by an assignment of these shares that are held in escrow until the loans are repaid. From the first set of interest free loans offered in 1998, $111,960 is outstanding which becomes due December 31, 2003. The second set of non-interest bearing loans offered on March 1, 2000 have $18,922 outstanding which is to be repaid in 2003 on the anniversary date of the loans. Loans are secured by the outstanding shares held in escrow. The value of the shares in escrow at December 31, 2002 is $142,665.

8 SEGMENTED INFORMATION BY GEOGRAPHIC SEGMENT

	Canada $	United States $	Consolidated $
Year-ended December 31, 2002			
Revenues	61,155	8,032	69,187
Earnings before taxes	11,802	205	12,007
Earnings	6,443	205	6,648
Cash flow from operations	33,088	3,799	36,887
Net capital expenditures	71,307	9,733	81,040
Identifiable assets	118,485	31,401	149,886
Year-ended December 31, 2001			
Revenues	48,491	6,832	55,323
Earnings before taxes	14,084	772	14,856
Earnings	7,760	772	8,532
Cash flow from operations	26,955	3,390	30,345
Net capital expenditures	18,855	13,852	32,707
Identifiable assets	64,864	26,905	91,769

9 PER SHARE INFORMATION

	2002	2001
Basic earnings per common share	**$0.34**	$0.50
Diluted earnings per common share	**$0.33**	$0.49
Basic cash flow from operations per common share	**$1.89**	$1.76
Diluted cash flow from operations per common share	**$1.85**	$1.73
Weighted average number of basic common shares outstanding	**19,524,412**	17,228,956
Weighted average number of diluted common shares outstanding	**19,916,356**	17,532,482

In computing the diluted net income and cash flow from operations attributable per common share, under the treasury stock method, the following number of shares were added to the weighted average number of common shares for the dilutive effect of employee stock options. For the year-ended December 31, 2002, 391,943 common shares were added (2001 – 303,526). Effectively, only "in the money" dilutive instruments impact the diluted calculations.

10 FINANCIAL INSTRUMENTS AND HEDGING ACTIVITY

The Company's financial instruments recognized in the financial statements consist of accounts receivable, accounts payable and bank debt. The fair value of the accounts receivable and payable approximate their carrying amounts due to the short-term maturity of these instruments, while the fair value of the bank debt credit facility approximates its carrying amount as the interest rate is a floating market rate.

The Company utilizes certain derivative financial instruments including crude oil swap contracts, crude oil option contracts, foreign exchange swap contracts and foreign exchange interest rate option contracts. The Company enters into these contracts to manage its cash flow exposure to the volatility of crude oil prices foreign exchange rates and interest rates. Financial derivative contracts outstanding at December 31, 2002 were as follows:

Term	Quantity/Day		Price/Barrel
Crude oil options (collars)			
May 1, 2002 to April 30, 2003	500 barrels	Call	U.S.$28.10 WTI
		Put	U.S.$24.00 WTI
June 1, 2002 to May 31, 2003	500 barrels	Call	U.S.$26.05 WTI
		Put	U.S.$22.00 WTI
September 1, 2002 to August 31, 2003	500 barrels	Call	U.S.$28.10 WTI
		Put	U.S.$24.00 WTI
January 1, 2003 to December 31, 2003	500 barrels	Call	U.S.$27.10 WTI
		Put	U.S.$23.00 WTI
Crude oil options (swaps)			
January 1, 2003 to December 31, 2003	500 barrels	Fixed	U.S. $26.75 WTI

The fair value of these collars based on quotes provided by brokers would result in a loss of U.S.$804,902 (CDN$1,269,813) if terminated at December 31, 2002.

Financial derivative contracts entered into subsequent to year-end are as follows:

Term	Quantity/Day		Price/Barrel
Crude oil options (collars)			
February 1, 2003 to December 31, 2003	500 barrels	Call	U.S.$30.00 WTI
		Put	U.S.$25.00 WTI
May 1, 2003 to December 31, 2003	500 barrels	Call	U.S.$28.00 WTI
		Put	U.S.$25.00 WTI
Crude oil options (swaps)			
June 1, 2003 to December 31, 2003	500 barrels	Fixed	U.S.$28.00 WTI

Foreign exchange swap

On September 6, 2002, Upton entered into an average rate forward foreign exchange contract. Based on monthly average rates, Upton will trade U.S.$1,000,000 per month at a strike price of U.S.$1.58 for the months of January through December 2003.

The fair value of this contract, based on quotes provided by brokers, would result in a gain of U.S.$62,317 (CDN$98,311) if terminated on December 31, 2002.

Interest rate hedge

In the third quarter, Upton entered into Forward Rate Agreements and hedged banker's acceptance rates on a portion of its debt for the period November 18, 2002 through October 9, 2003. Interest rate hedges outstanding as of December 31, 2002 were as follows:

Term	Amount $	Interest rate
November 18, 2002 to February 18, 2003	6,000,000	3.05
January 9, 2003 to April 10, 2003	6,000,000	3.07
January 9, 2003 to April 10, 2003	6,000,000	3.06
February 18, 2003 to May 20, 2003	6,000,000	2.86
April 10, 2003 to July 10, 2003	6,000,000	3.41
April 10, 2003 to July 10, 2003	6,000,000	3.19
April 10, 2003 to July 10, 2003	6,000,000	3.20
May 20, 2003 to August 19, 2003	6,000,000	3.27
July 10, 2003 to October 9, 2003	6,000,000	3.29
July 10, 2003 to October 9, 2003	6,000,000	3.24
July 10, 2003 to October 9, 2003	6,000,000	3.10

The fair value of these contracts, based on quotes provided by brokers, would result in a loss of $48,017 if terminated on December 31, 2002.

Interest rate hedges entered into subsequent to December 31, 2002 are as follows:

Term	Amount $	Interest rate
August 19, 2003 to November 18, 2003	7,000,000	3.04

11 COMMITMENTS

At December 31, 2002, the Company had non-cancellable long–term commitments related to its head office lease with the following future payments:

	$
2003	251,658
2004	251,658
2005	255,153
2006	265,683
2007	265,638
Thereafter	199,229

12 ACQUISITIONS

On April 25, 2002, pursuant to a Plan of Arrangement, the Company acquired all the outstanding shares of Empire Energy Inc. ("Empire"). The previous shareholders of Empire received, for each of their Empire shares, $0.5345 in cash and 0.134 of a common share of the Company. The acquisition has been accounted for using the purchase method and the purchase price has been allocated as follows:

	$
Purchase price	
Net working capital deficiency assumed	373
Petroleum assets	41,976
Future income tax liability	(11,709)
Site abandonment and restoration liability assumed	(64)
Long-term debt assumed	(3,552)
	27,024
Consideration	
Cash	13,960
3,499,970 common shares issued	12,880
Cost of acquisition	184
	27,024

13 SUBSEQUENT EVENT

On January 27, 2003 the Company announced that it has resolved to commence a process to explore strategic alternatives designed to maximize shareholder value.

SUPPLEMENTARY INFORMATION

Quarterly Financial Information

(in thousands of dollars expect per share amounts)	2002					2001				
	Q1	Q2	Q3	Q4	Total	Q1	Q2	Q3	Q4	Total
Revenues	**11,974**	**17,811**	**20,275**	**19,127**	**69,187**	15,341	14,223	14,630	11,129	55,323
Earnings (loss)	**1,794**	**2,113**	**3,001**	**(260)**	**6,648**	3,108	2,521	2,648	255	8,532
Earnings (loss)/share ($)	**0.10**	**0.11**	**0.15**	**(0.01)**	**0.34**	0.18	0.15	0.15	0.01	0.50
Cash flow from operations	**6,404**	**9,103**	**11,277**	**10,103**	**36,887**	8,690	7,524	8,175	5,956	30,345
Cash flow from operations/share ($)	**0.37**	**0.46**	**0.55**	**0.49**	**1.89**	0.50	0.44	0.47	0.35	1.76

Trading Range of Common Shares

	2002					2001				
	Q1	Q2	Q3	Q4	Total	Q1	Q2	Q3	Q4	Tota
High ($/share)	**4.10**	**4.25**	**4.05**	**4.60**		3.37	4.15	4.00	3.50	
Low ($/share)	**2.57**	**3.45**	**3.31**	**3.51**		2.74	3.15	2.70	2.80	
Close ($/share)	**3.70**	**3.60**	**3.70**	**4.15**		3.35	3.40	2.95	3.15	
Volume (thousands)	**2,626**	**4,335**	**3,901**	**3,284**	**14,147**	2,165	2,120	933	955	6,173

Abbreviations

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
BOE/d	barrels of oil equivalent per day
Bbls/d	barrels of oil per day
MMbbls	million barrels
API	American Petroleum Institute
Stb	stock tank barrels

Natural Gas

Mcf	thousand cubic feet
Mmcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
m^3	cubic metre
MMBTU	million British Thermal Units
gigajoule	trillion joules
m^3/d	cubic metres per day

Other

BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1Bbl of crude oil for 6Mcf of natural gas (this conversion factor is not based on either energy content or current prices)
MBOE	thousands of BOE
ARTC	Alberta Royalty Tax Credit

FIVE YEAR SUMMARY

(in thousand of dollars expect otherwise noted)

	2002	2001	2000	1999	1998
FINANCIAL					
Revenues					
Oil and gas Sales	**69,187**	55,323	56,616	31,139	29,713
Less: royalties	**(14,314)**	(11,229)	(14,242)	(8,172)	(6,157)
Revenue net of royalties	**54,873**	44,094	42,374	22,967	23,556
Expenses					
Operating	**9,489**	6,867	5,926	5,428	5,959
Interest	**1,852**	1,496	2,166	1,991	1,718
General and administrative	**4,433**	3,673	2,934	2,870	2,347
Depletion and depreciation	**26,120**	16,409	12,401	6,682	48,227
Site restoration	**972**	793	832	784	1,099
Cash flow from operations	**36,887**	30,345	29,100	11,490	12,418
per share – basic	**1.89**	1.76	1.67	0.65	0.73
per share- diluted	**1.85**	1.73	1.65**	0.64**	0.70
Net earnings (loss)	**6,648**	8,532	10,925	1,411	(23,143)*
per share – basic	**0.34**	0.50	0.63	0.08	(1.36)*
per share- diluted	**0.33**	0.49	0.62**	0.08**	anti-dilutive*
Balance Sheet Information					
Net capital expenditures – including corporate acquisition	**81,040**	32,707	29,547	11,059	20,444
Net capital expenditures – excluding corporate acquisitions	**39,064**	32,707	29,547	11,059	20,444
Bank debt	**50,104**	27,763	27,200	22,342	26,135
Working capital deficit	**2,709**	5,382	2,919	5,974	1,795
Total assets	**149,886**	91,769	81,353	67,529	63,927*
Shareholders' equity	**65,966**	46,614	38,275	28,661	27,837*
Common Share Information					
Shares outstanding at year-end					
Basic	**20,632**	17,162	17,196	17,731	17,639
Basic shares plus total options	**22,371**	18,649	18,824	19,443	19,044
Weighted average common shares					
Basic	**19,524**	17,229	17,448	17,670	17,028
Diluted	**19,916**	17,532	17,674**	17,825**	18,206
Equity market capitalization (December 31) (millions)	**85.6**	54.1	44.8	40.8	37.0
OPERATING					
Reserves (thousands of equivalent barrels)					
Proven	**10,027**	8,669	8,865	8,920	10,019
Probable	**5,446**	5,429	3,986	4,023	3,793
Total	**15,472**	14,098	12,851	12,943	13,812
Established	**12,750**	11,384	10,858	10,931	11,916
Production and Netbacks					
Average barrels of oil equivalent (boe) per day	**5,517**	4,589	4,263	3,522	4,441
Exit rate (December average) boe	**5,709**	4,575	4,933	4,578	3,731
Total barrels of oil equivalent (thousands)	**2,014**	1,675	1,560	1,285	1,621
Net realized price ($ per boe)	**34.36**	33.03	36.28	24.22	18.33
Operating costs ($ per boe)	**4.71**	4.10	3.80	4.22	3.68
Operating netbacks ($ per boe)	**22.54**	22.23	23.35	13.64	10.85
All–in cash netback ($ per boe)	**18.32**	18.13	18.64	8.94	7.66
Land Holdings					
Total land (thousands of net acres)	**345**	231	175	189	215
Undeveloped land (thousands of net acres)	**317**	202	151	166	195
Drilling Activity					
Gross	**50.0**	51	46.0	24.0	26.0
Net	**36.8**	32.5	35.6	22.0	19.9
Number of Employees					
Head Office	**25**	26	25	25	26
Field Office	**16**	15	14	13	12

* restated in accordance with the new accounting for income tax standard set by the Canadian Institute of Chartered Accountants

** restated to the treasury stock method

CORPORATE INFORMATION

DIRECTORS

William R. Dutton (5)
Chairman of the Board
Upton Resources Inc.
Calgary, Alberta

G. Scott Dutton (3)(5)
President and Chief Executive Officer
Upton Resources Inc.
Calgary, Alberta

Anthony H. Bogert (2)(4)(5)
Vice President
Nesbitt Burns
Ottawa, Ontario

D. Grant Devine (1)(3)(4)(5)
President
Grant Devine Management Incorporated
Regina, Saskatchewan

W. Craig Dutton (1)(4)(5)
President
Stone Hedge Funds Inc.
Humboldt, Saskatchewan

Garry H. Huntington (1)(2)(5)
President
Bryndan Holdings Inc.
Regina, Saskatchewan

Paul J. Schoenhals (2)(3)(5)
President
Petroleum Industry Training Services
Calgary, Alberta

J. Ronald Woods (1)(5)
President
Rowood Capital Corp.
Toronto, Ontario

(1) Member of Audit Committee
(2) Member of Compensation Committee
(3) Member of Corporate Governance Committee
(4) Member of Health, Safety and Environmental Committee
(5) Member of Reserves Committee

Notice of Annual General Meeting

The Annual General Meeting of the shareholders of Upton Resources Inc. will be held on Thursday June 5, 2003 at 11:00 a.m. (MST) in the Wildrose North room at the Sheraton Suites Eau Claire, 255 Barclay Parade SW, Calgary, AB

OFFICERS

G. Scott Dutton
President and Chief Executive Officer

Philip H. Grubbe
Vice President, Finance and
Chief Financial Officer

Gregory D. Henders
Vice President, Operations

Robin D. Irwin
Vice President, Land

Andre St. Onge
Vice President, Exploration

C. Steven Cohen
Corporate Secretary

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

ENGINEERING CONSULTANTS

Paddock Lindstrom and Associates Ltd.
Calgary, Alberta

FINANCIAL INSTITUTION

National Bank of Canada
Calgary, Alberta

BNP Paribas (Canada)
Toronto, Ontario

LEGAL COUNSEL

Burnet, Duckworth & Palmer
Calgary, Alberta

TRANSFER AGENT AND REGISTAR

The CIBC Mellon Trust Company
Toronto, Calgary, and Vancouver

HEAD OFFICE

3900, 205 - 5th Avenue SW
Calgary, Alberta T2P 2V7
Telephone: (403) 263-7373
Facsimile: (403) 263-7375

FIELD OFFICE

322 – 4th Street
Estevan, Saskatchewan S4A 0T8
Telephone: (306) 634-6484
Facsimile: (306) 634-6227

WEBSITE

www.uptonres.ca

UPTON'S TEAM

Exploration:
Julie Barnden
Melody Barrow
George Hassler
Darrol Proskow
Eric Strachan

Finance:
Kim Adair
Laura Berger
Darren Dittmer
Richard Dodds
Rebekah Salayka
Lee Voung
Jeanine Youde

Land:
Laury Chapman
Margaret Elekes
Sydney Gault
Lindsy Gordon
Elizabeth Urquhart

Operations:
Aaron Bradley
Jennifer Peters
Lloyd Schmidt
Heather Spencer
Darlene Ward

Estevan Field Office:
Sam Bakala
Dave Bayerle
Brad Clow
Ellen Delorme
Alan Dixon
Kristin Dupuis
Brad Dutton
Kim Harbourne
Greg Kerr
Jim Larter
Lynn Mack
Tammi Mann
Doug Moberg
Greg Swallow
Vic Young

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